CHAPTER 9 IPM MODELING RESULTS

All detailed summary results of IMP runs discussed in this chapter can be found in Volume II – Appendixes, Appendix A.

9.1 Least-Cost Scenarios
9.1.1 Base Scenario Results (Case 1)

Electric

The optimized energy system configuration with base case assumptions resulted in following changes:

- Yerevan TPP 160 MW Condensing Block Units 6 and 7 were retired by the optimization model in 2001. This is based on the poor heat rate of these units, limited availability and high fixed O&M required to keep the units in normal operation.
- Hrazdan TPP Condensing Block Units were not given an option to retire.
- ANPP was decommissioned in 2005.
- Hrazdan unit 5 440 MW Combined Cycle was installed in 2004, as the least-cost generation option available.
- System required another least-cost addition of 400 MW CC in 2011. Although the timing and amount of capacity slightly varies for other cases based on the demand forecast and ANPP retirement date, the technology selection in economic scenarios remains basically the same.

Steam

Steam optimization in Yerevan area took place as well. It was based on the base case steam assumptions and resulted in the following system changes:

- Due to the excess steam capacity in the area and unavailability of new steam generating technologies during this time, two (2) Yerevan TPP CHP units were retired in 2001.
- Upon the availability of new 82 MW CC CHP unit, the remaining two (2) CHP units at Yerevan TPP are replaced by this new unit in 2003.
- Hrazdan CHP units are decommissioned in 2002 (Units 1 and 3) and in 2003 (Units 2 and 4). They are replaced by refurbishment of one (possibly all 3) existing 200 MW condensing units to extract low-pressure steam.

Reserve Margin

In the Base Scenario the reserve margin levels continuously exceed the required 35% level. As presented below, the reserve margin capacity decreases from 2104 MW in 2000 to 1810 MW in 2003, and then, gradually increases to 2334 MW in 2020. This results from the least-cost solution where existing capacity is supplemented by new technologies' capacity additions that result in the lowest system cost.

The model results indicated that the Armenian electric power system's generation needs are determined predominantly by available energy requirements, rather than by the reserve margin capacity considerations. The amount of unserved energy and dumped energy are kept at zero.

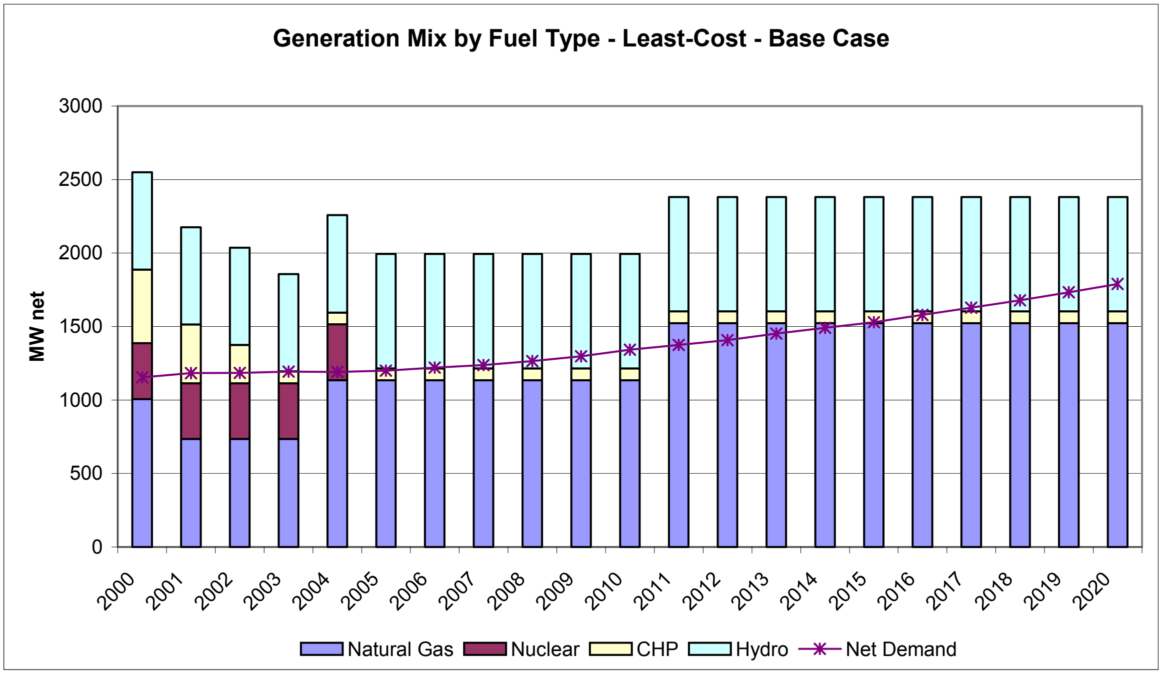
The optimal plan for the Base Scenario favors generation from rehabilitated hydro capacity, completion of partially built conventional steam cycle units (with conversion to combined-cycle), and gradual introduction of combined cycle technology. No new hydro, coal or nuclear technology are included in the optimal plan. The following table presents the capacity retirements and additions required for successful 2000-2020 period system operation.

Capacity Additions and Changes (MWnet) by Plant Type (10% DR)

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
N. Gas Other	0	-136x2 Yerevan 6 & 7	0	0	400 Hrazdan 5 CC	0	0	0	0	0	0	388 New CC
Nuclear	0	0	0	0	0	-380 ANPP Unit 2	0	0	0	0	0	0
Hydro	0	0	0	0	0	116 Vorotan Cascade Rehab.	0	0	0	0	0	0
Gas CHP	0	-56x2 Yerevan CHP 2 & 4	-46-92 Hrazdan CHP 1 & 3	82 MW CC CHP -2x56 MW Yerevan CHP 1 and 5 -46-92 MW Hrazdan CHP 2 and 4	0	0	0	0	0	0	0	0
Total	0	-384	-138	-170	400	-264	0	0	0	0	0	388

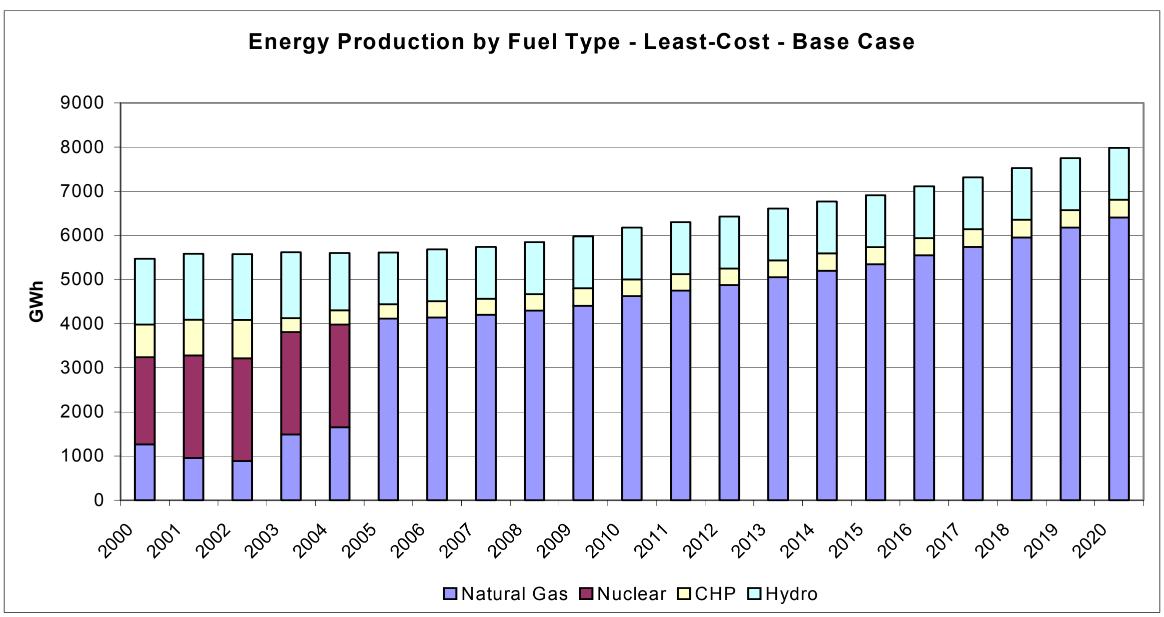
Combined cycle (CC) technology is selected in 2011 by the model based on the relatively low-cost base load capacity.

The following table provides the change of system capacity mix for the base case for 2000-2020.



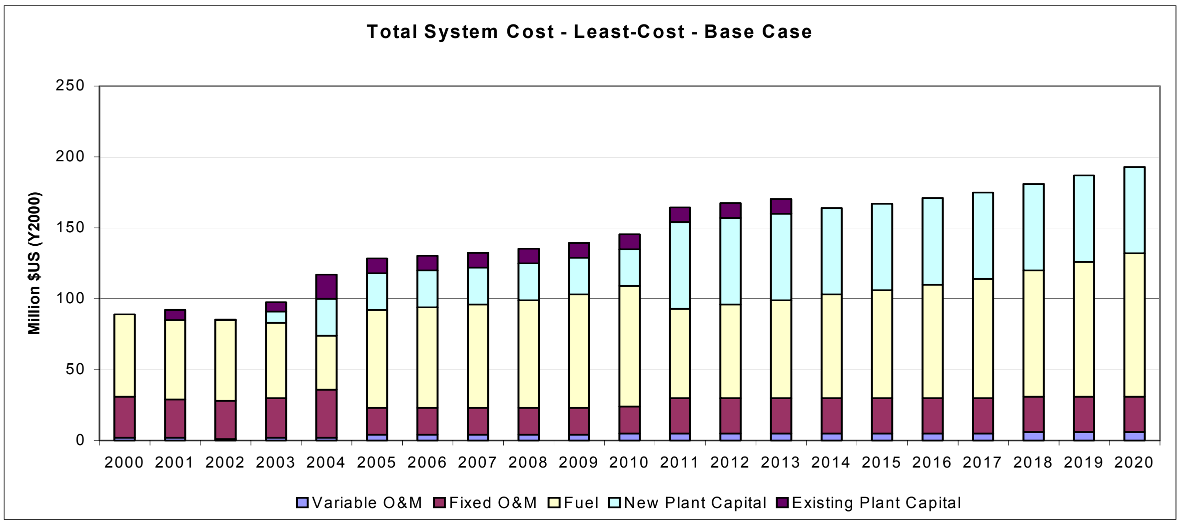
Energy Generation

The following graph represents the outlook of the energy generation by fuel type for the 2000-2020 period. It should be noted that with the phase-out of ANPP, its share of generation is picked up by gas-fired Hrazdan unit 5 CC and new 400 MW CC plants at 10% discount rate.



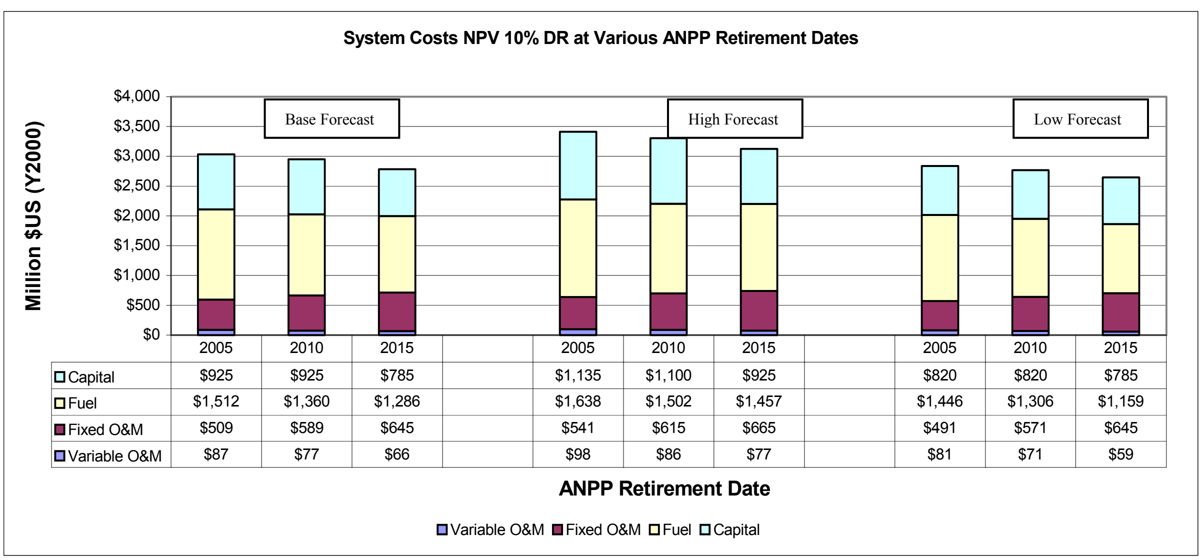
System Costs

Annual system costs, including fuel, variable and fixed O&M as well as existing facilities and new facilities capital requirements are shown below. It should be noted that fuel component provides for the largest expenditure throughout the analysis time period and significantly increases with ANPP shut-down in 2005. All figures are based on a 10% discount rate.



9.1.2 ANPP Retirement

Three ANPP retirement dates were analyzed in the least-cost (economic) matrix of study cases. These include 2005, 2010, and 2015.

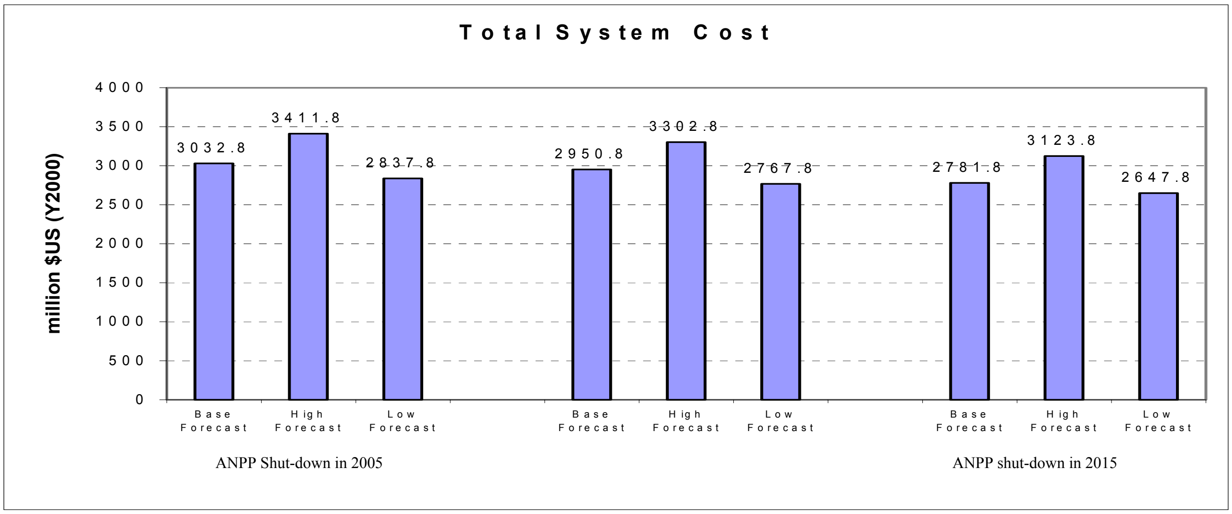


	2005	2010	2015		2005	2010	2015		2005	2010	2015
Capital	$925	$925	$785		$1,135	$1,100	$925		$820	$820	$785
Fuel	$1,512	$1,360	$1,286		$1,638	$1,502	$1,457		$1,446	$1,306	$1,159
Fixed O&M	$509	$589	$645		$541	$615	$665		$491	$571	$645
Variable O&M	$87	$77	$66		$98	$86	$77		$81	$71	$59

The retirement of ANPP in 2015 has the lowest total system cost impact primarily due to the fuel savings and deferral of new capital requirements. Fixed O&M is higher for this case because of the more expensive maintenance of existing ANPP.

9.1.3 Load Forecasts

Capacity additions as well as fuel costs are sensitive to the load forecast. The following graph shows the changes in the total system cost based on various demand forecasts and ANPP retirement dates.



The summary of capacity additions is presented below:

ANPP Retire Dem. Forecast	2005	2010	2015
<u>Base</u>	**Case 1** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2011 – 400 MW CC	**Case 2** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2011 – 400 MW CC	**Case 3** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2015 – 400 MW CC
High	**Case 4** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2009 – 400 MW CC 2017 – 400 MW CC	**Case 5** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2010 – 400 MW CC 2017 – 400 MW CC	**Case 6** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2015 – 400 MW CC 2017 – 400 MW CC
Low	**Case 7** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2014 – 400 MW CC	**Case 8** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2014 – 400 MW CC	**Case 9** 2003 – 82 MW CC CHP 2004 – 440 MW Hrazdan 5 2015 – 400 MW CC

It should be noted that ANPP retirement basically does not trigger any additional capacity. The 440 MW Hrazdan Unit 5 addition in 2004 is based on the optimal system configuration, and the program attempts to minimize overall system costs. Yerevan TPP Condensing Units 6 and 7 are retired and replaced by Hrazdan Unit 5 later, when load forecast is enough to substantiate this addition.

New 400 MW CC additions are the next least-cost choice after Hrazdan Unit 5. Again, these additions are triggered to satisfy increasing demand and as a result of the overall system cost optimization. Reserve margin remains high, since Hrazdan TPP units are considered expensive to operate based on the heat rate and high variable (fuel) component.

9.1.4 Yerevan CHP Steam System Development

Special attention has been paid to the Yerevan CHP system modeling. Cases 1-9 include the introduction of a new 82 MW CC CHP at Yerevan TPP. This is based on the following factors:

- Relatively high steam demand
- New 82 MW CC CHP is considered an IPP and has the benefit of using cheaper gas
- Fixed and variable costs of new unit are substantially lower than of existing Yerevan CHP units (assuming their normal periodic and major overhaul maintenance).

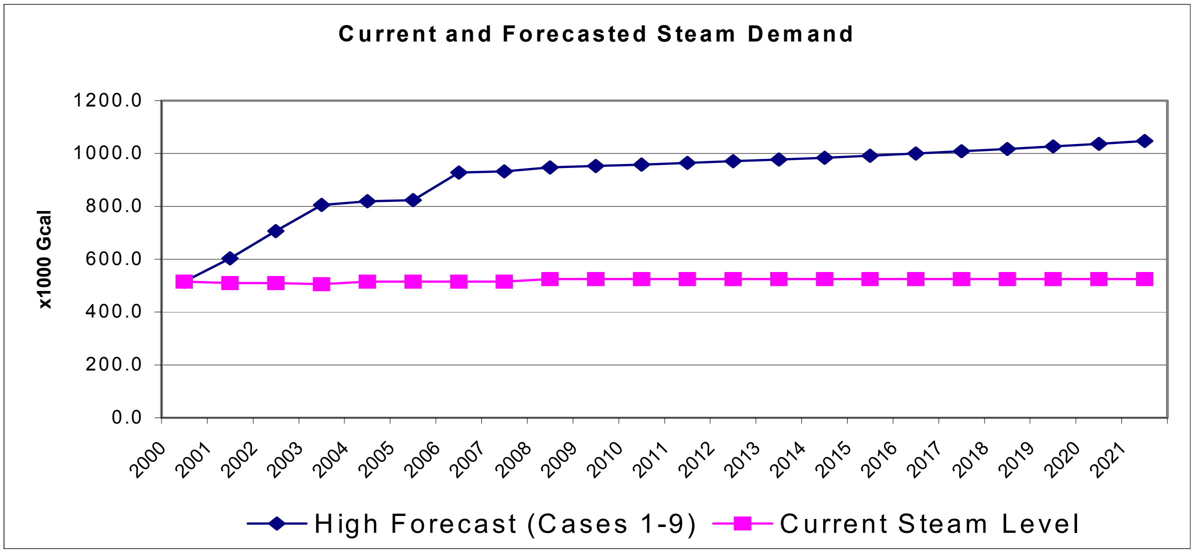
Several sensitivities were conducted to test economic attractiveness of new CC CHP unit at different assumptions.

Steam Demand

High forecasted steam demand as described in Chapter 3 and currently considered the base case for steam, results in the introduction of new 82 MW CC CHP at Yerevan TPP for all economic Cases 1-9.

However, such high steam demand is still questionable, since no firm decision is being made about major industrial steam consumers in the area, namely Nairit Factory and others. While the payment for steam issue represents another cornerstone of the steam generation decision it is outside of scope of this study.

The following exhibit presents the assumptions for annual steam demand at Yerevan area used in the analysis:



Sensitivities

To account for possible lower steam demand, two additional scenarios were developed.

1. The scenario assumes operation of new 82 MW CC CHP in condensing mode (i.e., no steam demand). IPM modeling showed that in this scenario, the new 82 MW unit is not considered most economical and other alternatives are selected before this unit is selected. Screening analysis performed in Chapter 8 also proves this result. Hrazdan Unit 5 completion, new 400 MW CC, and 100 MW gas turbine have lower installed life-cycle cost than 82 MW CC CHP.
2. Second steam sensitivity assumed current level of steam production with minimal increase to year 2020. In this sensitivity, the 82 MW CC CHP has not been selected for installation. Current steam demand is supported by two (2) existing units at Yerevan CHP part. The remaining two existing CHP units are shut-down staring 2001.

The following table presents 2000-2020 total system cost (in million Y2000 $US) comparison for high steam forecast (new 82 MW CC unit installation) and current steam level (utilization of existing Yerevan CHP units).

	Case 1 (High Steam Forecast)	**Case 1 Sensitivity (Current Steam Demand)**
Variable O&M	$87	$87
Fixed O&M	$509	$481
Fuel	$1,512	$1,547
Total Capital	$925	$764
TOTAL	**$3,033**	**$2,879**

Both Cases Assume: ANPP retirement in 2005, Base Demand Forecast, Base Fuel Price Forecast. All prices are in Y2000 M$US.

The introduction of a new CHP unit at Yerevan TPP results in total system cost difference of about $154 million $US.

In summary, the introduction of any new CHP capacity at Yerevan TPP can be only substantiated by increased steam demand. *Although it is recommended to install the new 82 MW unit in all economic cases based on the Ministry of Energy steam forecast, the detailed investigation of steam demand is proposed.* No definitive CHP project preparation/implementation should take place before such study is performed.

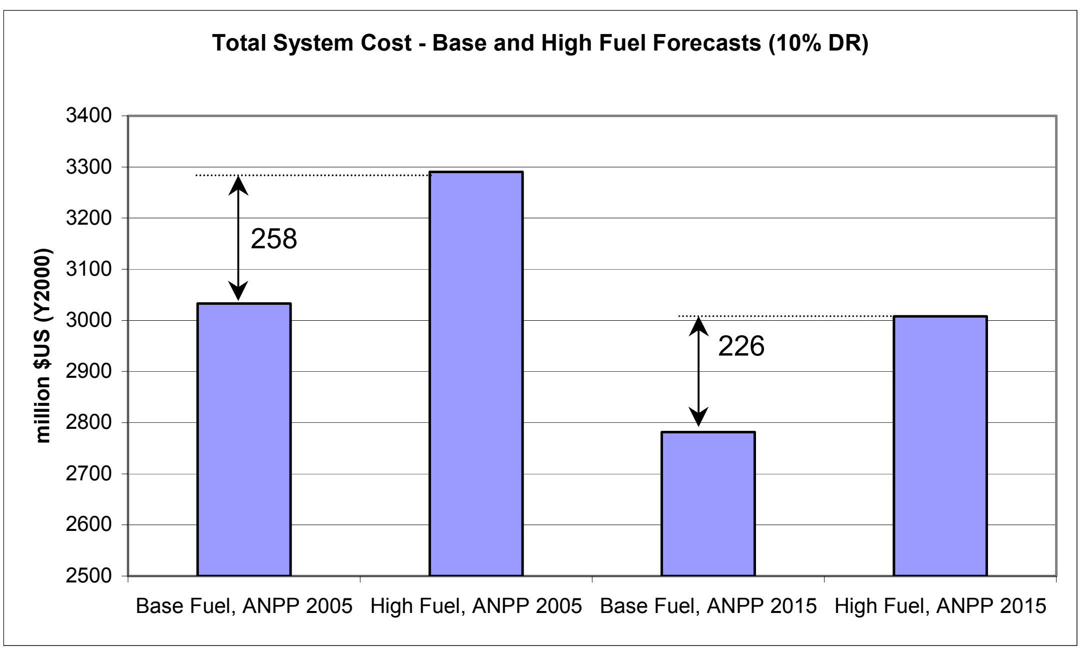
9.1.5 Fuel Price Forecast

Two fuel forecasts were used in the model runs. Detailed fuel forecast description can be found in Chapter 5. Fuel price (gas in all economic scenarios) impacts the utilization of the units as well as total system cost.

When comparing similar cases (with different fuel forecasts), i.e., Cases 3 and 2b, following is observed:

- Additional cost-effective capacity (100 MW gas turbine) is installed in high price fuel forecast. This unit replaces some of the existing less efficient gas-fired capacity and decreases the fuel cost component. The capital for new GT is less then the fuel cost component.

The following graph shows the difference in total system cost for various fuel prices and ANPP decommissioning in 2005 and 2015.



Additional sensitivity was performed for even higher gas prices. This sensitivity assumes that IPP gas ($50 per 1000 cm - assumed for all other cases) will not be available for all new technologies. Existing units gas arrangements ($79.1 per 1000 cm) were used for these sensitivities. The following table shows capacity additions/retirements for both cases:

Year	2001	2002	2003	2004	2005	2006	2010	2011	2014
Case 1	-2x136 MW Yerevan Units 6&7 -2x56 MW Yerevan CHP 2&4	-46-92 MW Hrazdan CHP 1&3	-2x56 MW Yerevan CHP 1&5 -46-92 MW Hrazdan CHP 2&4 +80 MW CC CHP Yerevan TPP	+400 MW Hrazdan Unit 5	-380 MW ANPP +116 MW Vorotan HPP Rehab.			+388 MW New CC	
Special Case 1 (w/in-creased fuel price)	-56 MW Yerevan CHP 2	-46-92 MW Hrazdan CHP 1&3	-46-92 MW Hrazdan CHP 2&4		-380 MW ANPP +116 MW Vorotan HPP Rehab.	+400 MW Hrazdan Unit 5	-2x136MW Yerevan Units 6&7		+388 MW New CC

Note: All capacities are net.

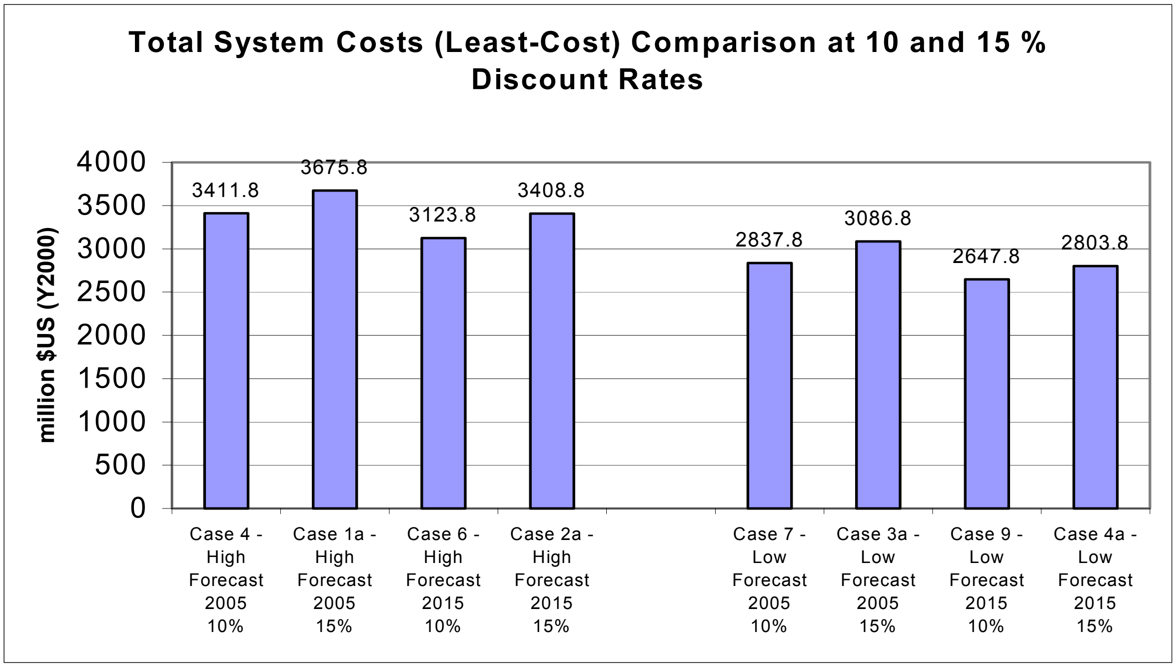
Total 2000-2020 system costs (in million $US Y2000) for these two cases are as follows:

	Case 1	**Special Case 1 (w/increased fuel price)**
Variable O&M	$87	$85
Fixed O&M	$509	$470
Fuel	$1,512	$2,125
Capital	$925	$625
Total	**$3,033**	**$3,305**

The comparison of these two cases shows the trade-off between increased fuel component in Special Case 1 due to the higher fuel prices and decrease in capital component due to the deferral of new capacity installation.

9.1.6 Discount Rates

While 10% discount rate was used for most of the analysis, for several cases in strategic matrix a sensitivity discount rate of 15% was used. The following chart provides a comparison of corresponding cases total system costs:



9.2 Strategic Scenarios

A number of strategic scenarios were analyzed as per strategic matrix in Chapter 7. The main purpose of this portion of the analysis is to replace all least-cost (i.e., gas-fired) technologies with generation sources that provide some relative fuel independence for Armenia. These include circulating fluidized bed unit burning local coal, new hydro power plants, and new nuclear unit. As mentioned before, these technologies are not least-cost and cannot be developed in Armenia in the short-term. Based on the long lead time for these to be developed, no strategic resource is available to generate energy before 2007. Any new generation needs before 2007 are assumed to be served by completed Hrazdan Unit 5.

Several strategic sensitivities are examined. These include:

- Cases 1s-5s: Installation of New Hydro capacity instead of combined cycle (in least-cost cases)
- Case 6s: Full optimization of system using strategic options
- Case 7s and 8s: Installation of New Nuclear capacity instead of combined cycle.

It should be noted that since strategic options are only available starting 2007, the up-front part (2000-2008) of the cost analysis between strategic and least-cost options is very similar.

Also, since the proposed new strategic options are fairly expensive, the model prefers to dispatch more expensive existing capacity in a several model runs, instead of adding new capacity. For that reason, some cases have less added capacity then their equivalents in least-cost cases.

9.2.1 Strategic Hydro Option

This option assumes the installation of three new major hydro power plants at Megri, Shnokh, and Loriberd sites with the total capacity of 211 MW.

Under the Base Load Forecast, in order to get accurate cost comparison, CC technology is replaced by new hydro.

Comparison Equivalence:

Least-Cost (Economic) Case		Strategic Case	
Case No.	**Additions**	**Case No.**	**Additions**
Base Demand Forecast			
1	388 MW CC – Y2011	1s	211 MW Hydro – Y2011 50 MW CFB – Y2020
3	388 MW CC – Y2015	2s	211 MW Hydro – Y2015 50 MW CFB – Y2020
2b	388 MW CC – Y2015 100 MW GT – Y 2019	3s[1]	211 MW Hydro – Y2015 50 MW CFB – Y2020
High Demand Forecast			
4	388 MW CC – Y2009 388 MW CC – Y2017	4s	211 MW Hydro – Y2009 50 MW CFB – Y2014 588 MW Nuclear – Y2016
6	388 MW CC – Y2015 388 MW CC – Y2017	5s	211 MW Hydro – Y2015 50 MW CFB – Y2015 588 MW Nuclear – Y2016

Note: All MW are Net

The total system cost figures (in million $US Y2000) are presented in the table below:

	1s	1	2s	3	3s	2b	4s	4	5s	6
Variable O&M	$80	$87	$63	$66	$63	$66	$78	$98	$61	$77
Fixed O&M	$480	$509	$628	$645	$628	$647	$573	$541	$713	$665
Fuel	$1,611	$1,512	$1,357	$1,286	$1,587	$1,500	$1,537	$1,638	$1,303	$1,457
Total Capital	$1,225	$925	$969	$785	$969	$795	$2,248	$1,135	$1,854	$925
Total	**$3,396**	**$3,033**	**$3,017**	**$2,782**	**$3,247**	**$3,008**	**$4,436**	**$3,412**	**$3,931**	**$3,124**
Difference in Cost (Strategic – Economic)	**$363**		**$235**		**$239**		**$1,024**		**$807**	

Although strategic options provide greater independence in terms of fuel supply, they do have higher overall cost. Difference in total system cost between economic (gas-fired) and strategic options are measured anywhere between $235 million and $1,024 million $US depending on the load demand sensitivity.

[1] Both Cases 3s and 2b assume high fuel forecast

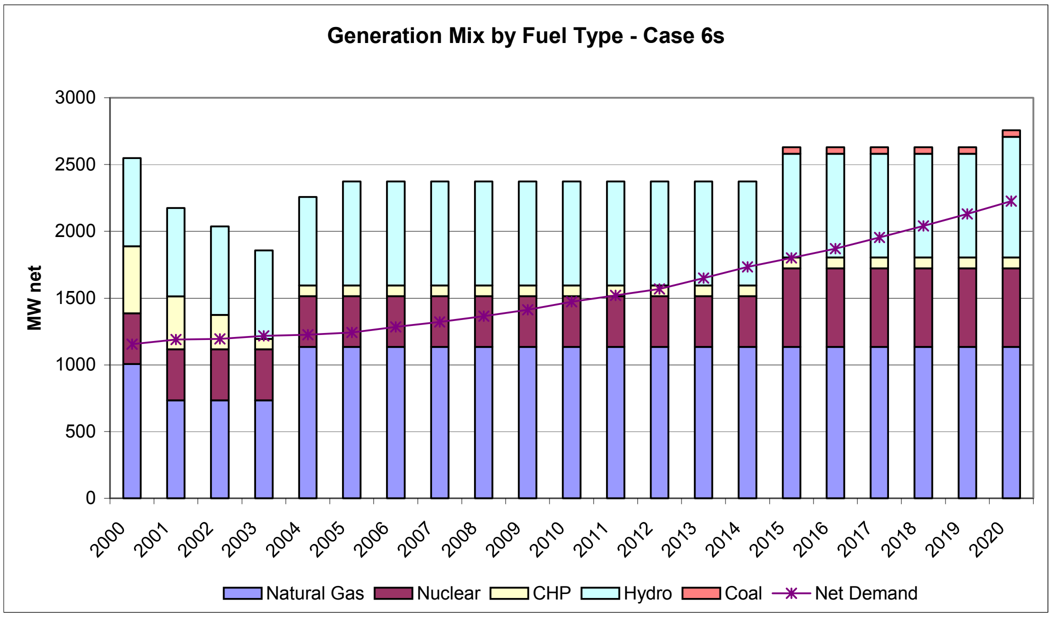
9.2.2 Full Strategic Optimization

Case 6s presents full optimization of strategic options for high demand forecast and high price fuel forecast. This case does not have corresponding economic case. The main purpose for this run was to fully optimize strategic options use.

Capacity Additions and Changes (MWnet) by Plant Type (10% DR)

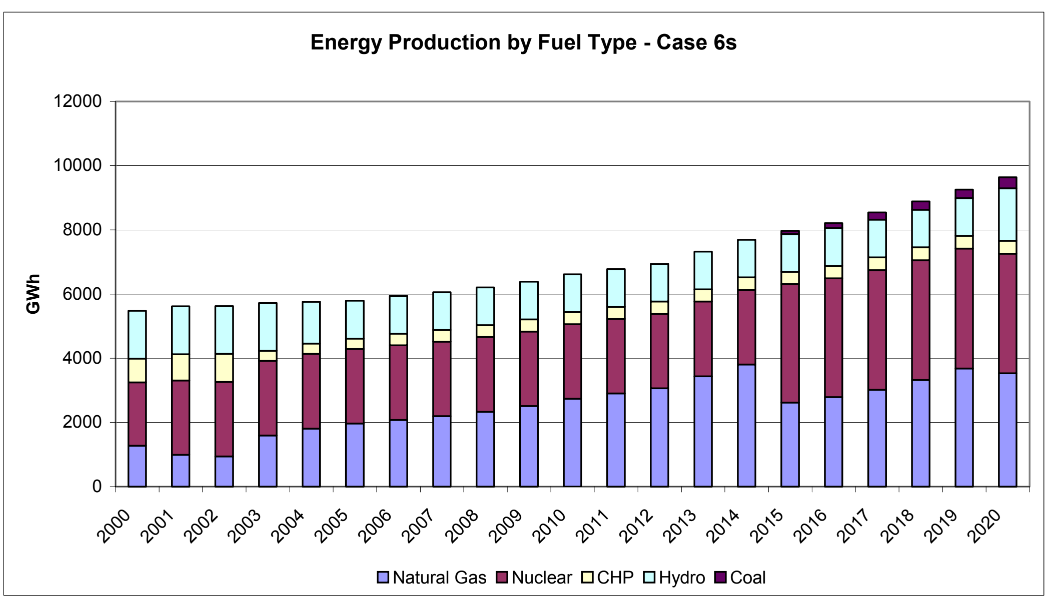
	2000	2001	2002	2003	2004	2005	2006	2015	2016	2017	2019	2020
N. Gas Other	0	-136x2 Yerevan 6 & 7	0	0	400 Hrazdan 5 CC	0	0	0	0	0	0	
Nuclear	0	0	0	0	0		0	-380 ANPP Unit 20 +588 New Nuclear	0	0	0	0
Hydro	0	0	0	0	0	116 Vorotan Cascade Rehab.	0	0	0	0	0	56 MW Loriberd 70 MW Shnokh
Gas CHP	0	-56x2 Yerevan CHP 2 & 4	-46-92 Hrazdan CHP 1 and 3	82 MW CC CHP -2x56 MW Yerevan CHP 1 and 5 -46-92 MW Hrazdan CHP 2 and 4	0	0	0	0	0	0	0	0
Coal								50 MW CFB				
Total	0	-384	-138	-170	400	116	0	258	0	0	0	126

The following chart indicates the change of system capacity mix for the strategic options case for 2000-2020.



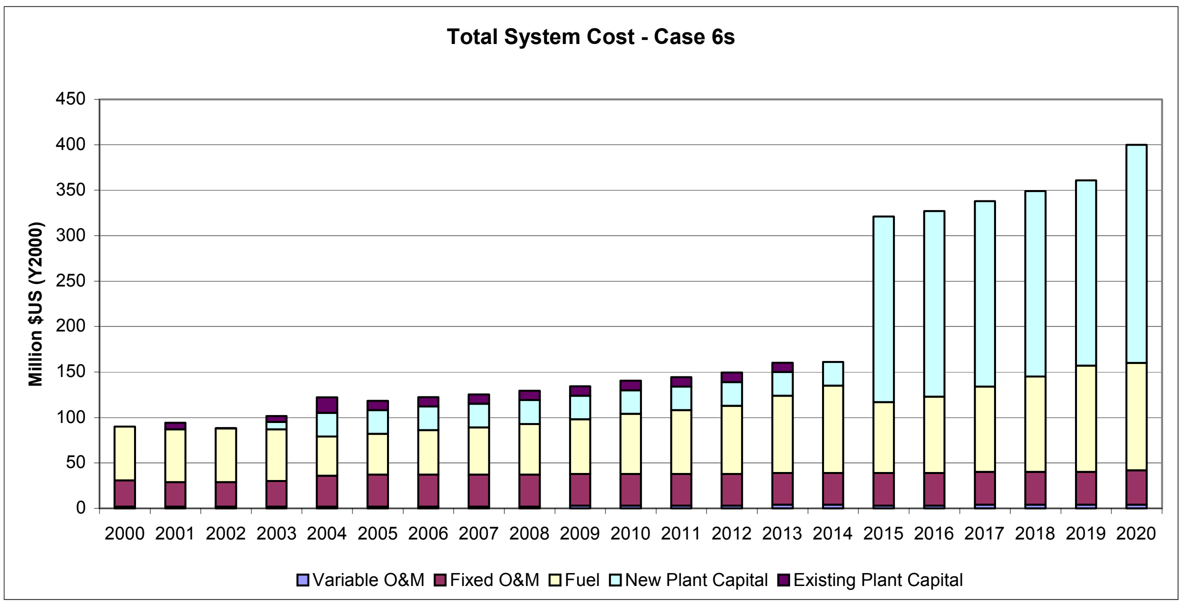
Energy Generation

The following graph represents the outlook of the energy generation by fuel type for the 2000-2020 period for strategic optimization. An increase in new nuclear generation and a decrease in gas generation should be noted.



System Costs

Yearly system costs, including fuel, variable and fixed O&M as well as existing facilities' and new facilities' capital requirements are shown below. It should be noted that the fuel component provides for the second largest expenditure throughout the analysis. New capital cost is the largest cost component that results from the very expensive technology cost for a new nuclear plant.



9.2.3 New Nuclear Option

Cases 7s and 8s analyze the cost of the new nuclear option when ANPP is retired in 2005.

Case No.	7s	1b	8s	4
Variable O&M	$58	$87	$64	$98
Fixed O&M	$619	$511	$655	$541
Fuel	$1,405	$1,758	$1,376	$1,638
Total Capital	$2,245	$935	$2,637	$1,135
Total	**$4,327**	**$3,291**	**$4,732**	**$3,412**
Difference in Cost (Strategic – Economic)	$1,036		$1,320	

Total 2000-2020 system costs are presented on graph below: